DIRECT TESTIMONY OF

UDAY VARADARAJAN

ON BEHALF OF

SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND

SOUTHERN ALLIANCE FOR CLEAN ENERGY

DOCKET NOS. 2017-370-E; 2017-305-E; 2017-207-E

Introduction and Qualifications

Q Please state your name and business address for the record.

A My name is Uday Varadarajan. My business address is 2490 Junction Place, Suite 200m Boulder, Colorado, 80301.

Q By whom are you employed and in what capacity?

A I am a principal at Rocky Mountain Institute ("RMI"), where I conduct financial, policy, and regulatory analysis to help drive a just transition to clean energy.

Q Please describe the Rocky Mountain Institute.

A RMI is an independent, nonpartisan nonprofit cofounded in 1982 by Amory Lovins, RMI's chairman emeritus and chief scientist. RMI engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables.

Q Please summarize your professional and educational qualifications.

A Before joining RMI, I was a Principal at Climate Policy Initiative Energy Finance (CPI-EF), where I managed CPI-EF's San Francisco team. At CPI, I led the development of financial, regulatory, and policy data analytics and tools to help consumers, utilities, and communities in states across the United States (including New York, Colorado, Missouri, Minnesota, and Utah) realize the benefits from a just and equitable transition from uneconomic dirty resources to clean energy. Prior to my role at CPI, I served as a program examiner in the U.S. White House Office of Management and Budget (OMB), where I oversaw the budget for U.S. Department of Energy (DOE) energy efficiency and renewable energy programs and the cost assessment and approval of the first $8 billion in DOE loans to automakers, including loans to Tesla and Nissan to build electric vehicles. Before joining OMB, I was an AAAS Science and Technology Policy Fellow at the Department of Energy and then on detail to the staff of the U.S. House of Representatives, Appropriations Committee. Prior to my time in Washington, DC, I was a postdoctoral fellow in theoretical physics in the Weinberg Theory Group at the University of Texas at Austin. I received an AB in Physics from Princeton University and an MA and PhD in Physics from the University of California, Berkeley.

Q Have you previously filed testimony in a regulatory proceeding?

A Yes. I have previously filed testimony in regulatory proceedings focused on depreciation rates and financial mechanisms in the states of Colorado (16A-0231A – depreciation rate revision, on behalf of Western Resource Advocates), Minnesota (E015/GR-16-664 – rate case, on behalf of several Minnesota Clean Energy Organizations), and New York (15-E-0302 – large scale renewables program, on behalf of NYSERDA).

Q On whose behalf are you testifying in this proceeding?

A I am testifying on behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy.

Q How is your direct testimony organized?

A My testimony is organized into the following sections:

Q Are you sponsoring any exhibits?

A Yes. I am sponsoring one Exhibit—UV1

I. PURPOSE AND SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q What is the purpose of your direct testimony in this proceeding?

A I performed an analysis to quantify the current and future costs to ratepayers of six scenarios, assessing three different financing approaches for each scenario. Specifically, for each scenario I looked at 1) traditional utility financing through the amortization of a regulatory asset, 2) the use of dedicated corporate bond financing repaid through a dedicated stream of ratepayer funds to finance immediate cost recovery, and 3) the use of a ratepayer-backed bond securitization to finance immediate cost recovery. My testimony will assist the Commission in understanding the components of Dominion's proposal compared to other options, and demonstrate the value for customers of refinancing the nuclear capital costs.

Q Please summarize the primary conclusions of your direct testimony.

A My primary conclusions are that:

i) Securitization could save ratepayers between $0.5 and 2 billion dollars relative to the use of traditional utility financing of the unrecovered capital costs for the units, equivalent to annual savings of between $50-230 million, or roughly 2-10% of current annual ratepayer bills,

ii) Securitization of a non-merger option can provide greater cost savings as compared to the Customer Benefits Plan and merger proposed by South Carolina Electric and Gas Company ("SCE&G" or "the Company") and Dominion Energy, and

iii) The Customer Benefits Plan with securitization could provide great cost savings to customers, though a scenario that includes most of the elements of the Customer Benefits Plan, but does not provide an up-front rebate to current customers, could provide a better balance between savings to current and future ratepayers and could also reduce the risk of potential ratings impacts.

II. BACKGROUND ON THE V.C. SUMMER NUCLEAR PROJECT AND POTENTIAL ROLE OF SECURITIZATION

Q Please provide an overview of the overarching decisions before the Commission regarding V.C. Summer units 2 and 3.

A At a very high level, the task before the Commission is to decide two key questions regarding the roughly $4.7 billion in unrecovered construction costs incurred by SCE&G for V.C. Summer units 2 and 3:

i) How much of those costs are to be recovered? What portion (if any) of the capital costs were prudently incurred and should be allowed to be recovered through rates?

ii) <u>How should those costs be recovered?</u> When will costs be recovered, how will those costs be split between past, current, and future ratepayers, and how will the recovery of costs be financed?

Q What specific decisions relevant to how costs are to be recovered are before the Commission?

A The Company has laid out several scenarios for the Commission to consider that differ both in the subset of costs to be recovered as well as in how those costs are recovered. The specific decisions about how costs are to be recovered include:

i) <u>How long to amortize the nuclear abandonment regulatory asset</u> – the Company has introduced scenarios with cost recovery periods of 20, 50, or 60 years. Just as with a mortgage, the longer the time period over which a cost is amortized, the lower the annual payments will be—but at the expense of increasing the overall total payment of financing costs and burdening ratepayers far into the future.

ii) <u>Approval of an up-front rate credit</u> – the Company has proposed scenarios with and without up-front bill credits / refunds to the ratepayers who have borne substantial costs in rates while the units were under construction.

iii) <u>Approval of the merger and equity financing of the up-front rate credit</u> – perhaps the most consequential decision before the Commission is whether a proposed merger of the Company with Dominion Energy is in the long-term interest of customers. In particular, the merger includes equity financing for SCE&G to fund an up-front rate credit for ratepayers who have previously paid nuclear costs.

iv) Approval of a refund pool – the Company has proposed scenarios in which future rates are reduced through the use of a refund pool to avoid any further rate increase associated with plant costs.

v) Passthrough of the Toshiba payment to ratepayers – the $1.1 billion in net proceeds from the payment made by Toshiba is recorded as a regulatory liability in the Company's books, and is expected to be passed through to ratepayers. However, the timing and mechanism of passing those funds back to ratepayers is a decision before the Commission. The Toshiba payment could be provided as an up-front credit to previous ratepayers, or it could be returned over time as the corresponding regulatory liability is amortized over the life of the nuclear abandonment regulatory asset.

vi) Approval of the Company's proposal to pass through the tax impacts of the Tax Cuts and Jobs Act to ratepayers – there are several different approaches to incorporating into rates the impact of the federal Tax Cuts and Jobs Act. These impacts flow from the reduction in corporate tax rates from 35% to 21% for 2018 tax year and the corresponding decrease in the value of any deferred tax assets or liabilities outstanding at the end of 2017. Any taxes on income that the Company had been able to put off paying until after the end of 2017 are now to be assessed on that income at a lower rate, resulting in a smaller liability. Similarly, any tax deduction that the Company was carrying forward to future years will now reduce income taxes at the lower rate, also reducing its value.

Q Are these decisions unique to the V.C. Summer situation?

A In my experience, every proceeding dealing with stranded costs requires a decision on the amortization period for the regulatory assets associated with the abandoned project costs. However, there are several interlinking factors that make this situation unique, including the fact that the abandonment:

i) involved a very large unrecovered plant balance relative to the Company's total rate base,

ii) involved a plant that will never benefit past, present, or future ratepayers,

iii) has already resulted in significant costs to ratepayers,

iv) occurred just before the Tax Cuts and Jobs Act was passed and went into effect, and

v) is being considered in concert with a proposed merger.

Q How do all of these decisions relate to your analysis?

A The analysis I performed focused on both untangling the impacts of these decisions by quantifying the current and future costs to ratepayers of six scenarios (including the three discussed by the Company in its Joint Application and three additional scenarios) and assessing how three different financing approaches change the potential impact under each scenario. For each scenario, I modeled the cost to ratepayers associated with recovery of allowed costs via:

i) <u>Regulatory Asset</u> – traditional utility financing through the amortization of a regulatory asset,

ii) <u>Corporate Bond</u> – the use of dedicated corporate bond financing repaid through a dedicated stream of ratepayer funds to finance immediate cost recovery, and

recovery, and

iii) Securitization – the use of a ratepayer-backed bond securitization to achieve immediate cost recovery.

The analysis compared each of these cost recovery financing cases in order to identify the lowest cost options for SCE&G customers.

Q What is securitization and why is it relevant in this proceeding?

A CCL and SACE have introduced testimony from former Colorado Public Utilities Commission Chairman Mr. Ron Binz, which explains the concept of securitization and its benefits in situations involving stranded assets, including the abandonment of a nuclear plant. As recommended by Mr. Binz, the Commission can condition its approval of the merger on the use securitization for the recovery of any approved stranded costs of the abandoned V.C. Summer units, and make the merger condition contingent on legislative action.

III. OVERVIEW OF ANALYSIS

Q Please provide a brief overview of the analysis that led to your conclusions.

A I modeled six scenarios, including the three scenarios the Company included in its recent Joint Application—the Customer Benefits Plan, the No Merger Plan, and the Base Request—as well as a scenario I've called the Act No. 258 Rate Reduction scenario, which is discussed by SCE&G's witness Iris Griffin in subsequently-filed testimony.[1] I also modeled a scenario based on the Customer Benefits Plan but without the $1.3 billion up-front bill credit, and a scenario in which no additional nuclear costs were allowed in rates. For each of these six scenarios, I calculated how recovery of nuclear costs affects the annual revenue requirements and the present value of revenue requirements (PVRR)

[1] *See* Griffin Direct Testimony at p. 36 and Exhibit ING-4.

under three different financing cases—the regulatory asset case, the corporate bond case,[2] and the securitization case.[3] These metrics allowed me to assess the relative impacts on current and future customer costs.

Q Please provide more background on the six scenarios you analyzed.

A The Customer Benefits Plan, the No Merger Plan, and the Base Request scenarios and their assumptions are all derived from the options presented in SCE&G and Dominion's Joint Application. Each of the three scenarios start from the assumption that SCE&G has received approval to recover roughly $3.5 billion in nuclear costs so far under the Base Load Review Act, and that the Company has incurred a total of $4.7 billion in costs (exclusive of transmission costs), leaving $1.2 billion in nuclear costs yet to be approved for recovery. The three scenarios then offer reductions to the amounts already approved for inclusion in rate base and/or those yet to be approved—and offer different mechanisms (including rate reductions, refund pools, and bill credits) to pass

[2] This approach would authorize the Company to issue additional amortizing senior corporate debt (on a pari passu basis with existing senior corporate debt) sized to provide full recovery of any approved nuclear costs. The proceeds from this bond issuance would be available to the Company to, for example, offset more expensive debt or buy back stock. The financing costs associated with servicing this additional debt would be reflected in rates through a new dedicated surcharge on customer bills, sized and adjusted periodically to cover expected future debt service payments. Importantly, as this debt would be deemed to be repaid through a dedicated surcharge, I assumed that this debt would be disregarded in future calculations of the leverage for ratemaking purposes. The primary benefit of this approach would be to reduce the financing costs for future ratepayers associated with recovery of nuclear capital costs by substituting 100% debt for the mix of debt and equity in traditional utility financing—but without impacting the carrying charge on non-nuclear recovery assets. As SCE&G's allowed cost of debt is 6% while the grossed up approved rate of return used to calculate carrying costs in traditional utility financing is closer to 10%, this approach can substantially reduce the carrying cost of nuclear recovery assets without negatively impacting the Company's earnings from the remainder of its rate base. I assume that the amortization period of the bond is 20 years.

[3] As with the corporate bond case, the proceeds from this bond issuance would be available to the Company to, for example, offset more expensive debt or buy back stock. This approach requires dedicated authorizing legislation to provide debt investors with assurances that the debt would be repaid regardless of the financial status of the utility or any changes in utility customer base or regulatory environment. With such legislation in place, the securitized bonds can achieve the highest possible credit rating (Aaa or AAA) and therefore offer a substantially lower cost of debt—closer to 3-4% relative to a traditional corporate bond. I assume that the amortization period of the bond is 20 years.

those reductions on to customer bills. I take no position on whether SCE&G actually is legally entitled to full recovery of the nuclear costs incurred. Further, I note that each of these scenarios also involve offsetting contributions to rate base from net accumulated deferred income taxes and related regulatory liabilities (net of assets) of between $400-830 million.

Q Please start with the Customer Benefits Plan.

A In the Customer Benefits Plan scenario, Dominion and SCANA merge and recover $3.3 billion of its incurred nuclear costs (or $2.8 billion net of net deferred tax liabilities) in rates over a 20-year period at an allowed 10.25% return on equity (at a 52.81% equity ratio) and a 5.85% allowed return on debt for an allowed rate of return (exclusive of the deductibility of interest) of 8.17% (or 7.45% inclusive of deductibility of interest).[4] This scenario includes a refund pool, $1.3 billion up-front rebate, and additional write-downs compared to the other scenarios.

Q And the No Merger Plan?

A In the No Merger Plan scenario, SCE&G recovers $3.1 billion (or $2.7 billion net of net deferred tax liabilities) in rates over a 50-year period. The Toshiba settlement payment is not used for an upfront credit, but to offset the amount of construction costs ratepayers must pay off over time. This scenario does not include a refund pool and there are fewer write-downs than in the Customer Benefits Plan scenario.

Q And the Base Request?

A In the Base Request scenario, SCE&G recovers $3.6 billion (or $3.3 billion net of net deferred tax liabilities) in rates over a 50-year period. The Toshiba settlement payment is not used for an upfront credit but rather as an offset to the construction costs

[4] *See, e.g.*, workpapers provided in response to ORS request 1-116.

included rate base. This scenario does not include a refund pool or write-downs. Further, in this scenario, SCE&G would request recovery in the future of an additional $628 million in costs associated with nuclear fuel inventory ($86m), replacement capacity ($180m), and nuclear-related regulatory assets not currently in rate base ($361m).

Q Were all of the assumptions you used included in the original Joint Application?

A No. Many of the assumptions that underlie these plans were not explained thoroughly in the Joint Application, but were later clarified in the Companies' testimony and responses to Office of Regulatory Staff Audit Information requests.[5]

Q Please describe the Act No. 258 Rate Reduction scenario.

A The Act No. 258 Rate Reduction scenario is based on an option outlined by SCE&G's witness Iris Griffin.[6] This scenario is the Company's rendering of making the 15% rate-cut the South Carolina General Assembly enacted in June 2018 permanent. Importantly, the Company has assumed that it will need to take a larger write-down in this scenario.

Q Please describe the Customer Benefits Plan without the $1.3 billion up-front credit.

A The scenario of the Customer Benefits Plan without the $1.3 billion up-front bill credit, has many of the same assumptions as the Customer Benefits Plan, except that the Toshiba payment offsets ratebase and there is no need for Dominion to provide the equity financing to enable upfront cash rebates.

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[5] Specifically, the clarifications and workpapers accompanying the Company's responses to ORS Information requests 1-116, 1-118, 1-134-1-136, 1-140, 1-143, 1-148-1-152 provided additional information critical to the modeling performed.

[6] *See* Griffin Direct Testimony at p. 36 and Exhibit ING-4.

Q What was the last scenario you analyzed?

A Finally, I analyzed a "zero cost recovery" scenario, in which no additional nuclear costs are allowed in rates. This scenario serves as a baseline against which to compare the other five scenarios.

Q What are the primary ways that these scenarios differ from each other?

A These scenarios reflect the different decisions before the Commission regarding the costs to be recovered as well as the method by which those costs are recovered. While I have focused on just six scenarios, hewing closely to the combinations of decisions implicit in the Company's scenarios, the number of potential scenarios is large. Different decisions on any of the key issues discussed above—including the total costs to be recovered, approval of the merger with Dominion, the amortization period, the implementation of up-front bill credits and/or refund pools, the treatment of the Toshiba payment, and the treatment of tax reform—would result in additional scenarios.

Q What is the significance of all these decisions for ratepayers?

A Each variant within a scenario has different ratepayer impacts in the long-term. As an example, the $1.1 billion Toshiba payment could reduce the amount of the unrecovered V.C. Summer construction costs included within rate base, thereby reducing ongoing capital costs over time. On the other hand, that payment could be immediately refunded to customers via an up-front bill credit, which benefits current customers, but leaves a larger amount in rate base that drives up costs for future ratepayers.

Q What additional issues need to be considered in evaluating the impact of these financing options on current and future customer costs?

A The results presented here assume that the choice of scenario or financing options do not impact the allowed equity and debt costs. Different scenarios and financing options could impact the Company's credit rating in different ways. For example, if a nuclear cost disallowance or a financing decision results in a credit downgrade that pushes the credit rating of the Company below investment grade for a substantial period of time, the Company's cost of debt could increase over time, thereby increasing future carrying charges and future rates relative to the assumed costs in our model. A credit rating downgrade could ultimately reduce access to credit and liquidity and increase the risk of default as well as decrease the Company's ability to make unexpected plant repairs or respond to storm damage.

However, these shifts in the cost of debt are likely to occur only when existing debt matures and needs to be rolled over and as the Company issues new debt. As the bulk of the Company's debt (over $4.4 billion) is long-dated, with maturities in the 2030s and beyond, the impacts on the present value of revenue requirements are likely to be muted. As a result, I believe that these cost impacts are likely second order effects; that the relative impacts of a potential future credit downgrade are smaller than the differences in costs between scenarios and financing options that are currently captured by the model. In addition, the Company has several choices regarding the use of proceeds from securitization and can structure a special purpose vehicle to help mitigate any downside credit risks associated with use of securitization. Further, securitization itself could provide a low-cost alternative to give the Company greater flexibility to address emergency financing needs for storm damage repair. Securitization has been used precisely for this purpose in several states over the last decade, including Louisiana, Arkansas, and Texas.

IV. RESULTS

Q What are the general results of your analysis?

A I find that securitization can provide substantial benefits, providing between $0.5-$2.0 billion in cost savings for current and future ratepayers relative to traditional utility financing via a regulatory asset. Securitization can provide large cost savings even without a merger or any of the benefits associated with the Customer Benefits Plan. My analysis also shows that altering specific elements of the Customer Benefits Plan can reduce costs even further. The Customer Benefits Plan with alterations like securitization could provide greater cost savings to customers than anything proposed in the application, though a scenario that includes most of the elements of the Customer Benefits Plan, but does not provide an up-front rebate to current customers, could provide a better balance between savings to current and future ratepayers and could also reduce the risk of potential ratings impacts.

Q Which scenario—using traditional utility financing—delivers the lowest cost to ratepayers?

A Under traditional utility financing, the continuation of Act No. 258 results in the lowest cost for ratepayers, lower even than the Customer Benefits Plan offered in the merger.[7] If traditional utility financing is used to recover nuclear costs, the lowest cost option for ratepayers (excluding potential credit ratings impacts) on a present value basis

[7] Except the Zero Cost Recovery case, which provides a baseline for costs in the absence of nuclear recovery costs.

($1.4bn) and on an annual basis ($134m in year 2 costs) would be the continuation of the rate reductions from Act No. 258. However, making the Act No. 258 scenario permanent with traditional utility financing would require evaluation of credit consequences for the Company.

Figure 1: Regulatory Asset – PV of Revenue Requirements

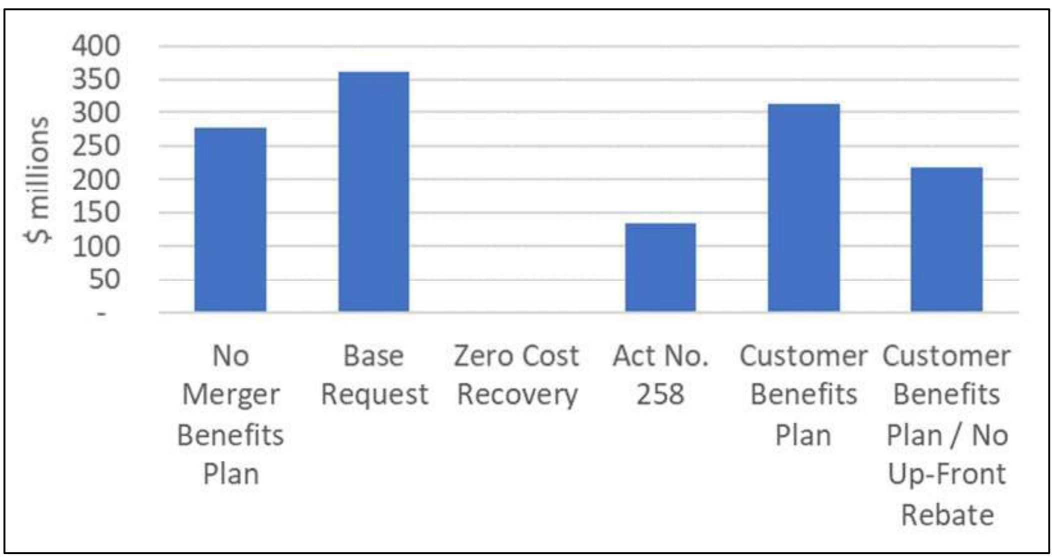

Figure 2: Regulatory Asset –Revenue Requirements in Year 2

Q Please discuss how the Customer Benefits Plan compares with other options.

A As I just mentioned, the Customer Benefits Plan is not the lowest cost option for ratepayers under traditional utility financing. The Customer Benefits Plan features similar benefits to the Act No. 258 scenario in terms of impacts on present value of revenue requirements ($1.6bn), but has very different impacts on current versus future ratepayers. While the plan would provide a large benefit to current ratepayers ($1bn in net rebates to current ratepayers), it would result in substantially higher ongoing costs for future ratepayers over the next 20 years ($313m in year 2) as compared to costs over the next 50 years from continuation of Act No. 258 rate reductions.

Q What did you find regarding securitization?

A Across all scenarios, securitization can save between $0.5-2.0bn in total costs, $50-235m in annual ongoing ratepayer costs (in year 2) relative to traditional utility financing via a regulatory asset. Securitization also reduces annual ongoing ratepayer costs by between $50-235m in year 2. That is anywhere from 2-10% reduction in total ratepayer bills relative to the use of traditional utility financing of the unrecovered capital costs for the units.

Figure 3: Savings from Securitization - PVRR

Figure 4: Savings from Securitization – Year 2 Revenue Requirement

Q Are the securitization results from your analysis consistent with any other analyses you have reviewed?

A Yes. The Office of Regulatory Staff commissioned a report from Bates White on securitization. The July 18, 2018 report entitled *Securitization and Its Potential Role in Financing V.C. Summer Nuclear Costs* similarly concludes that "Securitization of $3.3 billion could reduce the total estimated cumulative revenue requirement ***by as much as $1.5 billion*** over 20 years based on certain simplifying assumptions." (emphasis added).[8]

Q Which scenario using securitization provided the greatest savings to ratepayers?

A Of the scenarios I analyzed, the Customer Benefits Plan with securitization can deliver the greatest savings to ratepayers. The Customer Benefits Plan with securitization—with or without an up-front credit—provides substantial cost reductions, especially relative to the no merger benefits plan and base request scenarios proposed by the Company. The cost savings on both a present value basis and in annual costs are

[8] https://www.regulatorystaff.sc.gov/Documents/News%20Archives/BW%20Securitization%20Report%20Jul182018.pdf

comparable to the savings in the Act No. 258 scenario. However, one significant difference between the Customer Benefits Plan and Act No. 258 scenarios is that the Customer Benefits Plan provides the Company cost recovery on a much larger portion of the nuclear unit costs. As a result, the securitized bond is significantly larger in the two Customer Benefits Plan scenarios relative to the Act No. 258 scenario, and so are the corresponding financing costs savings.

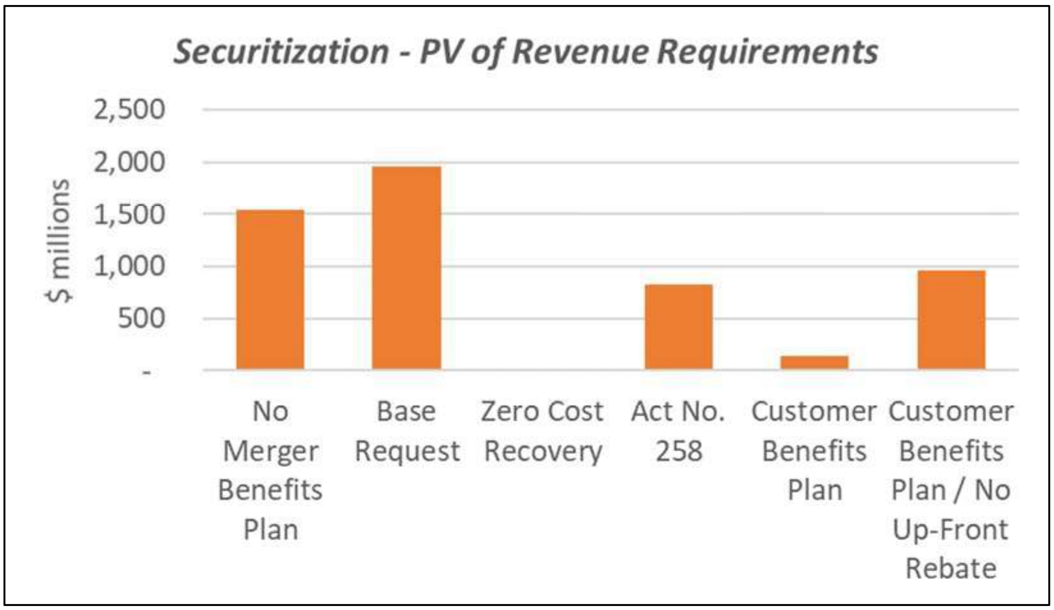

Figure 5: Securitization – PV of Revenue Requirements

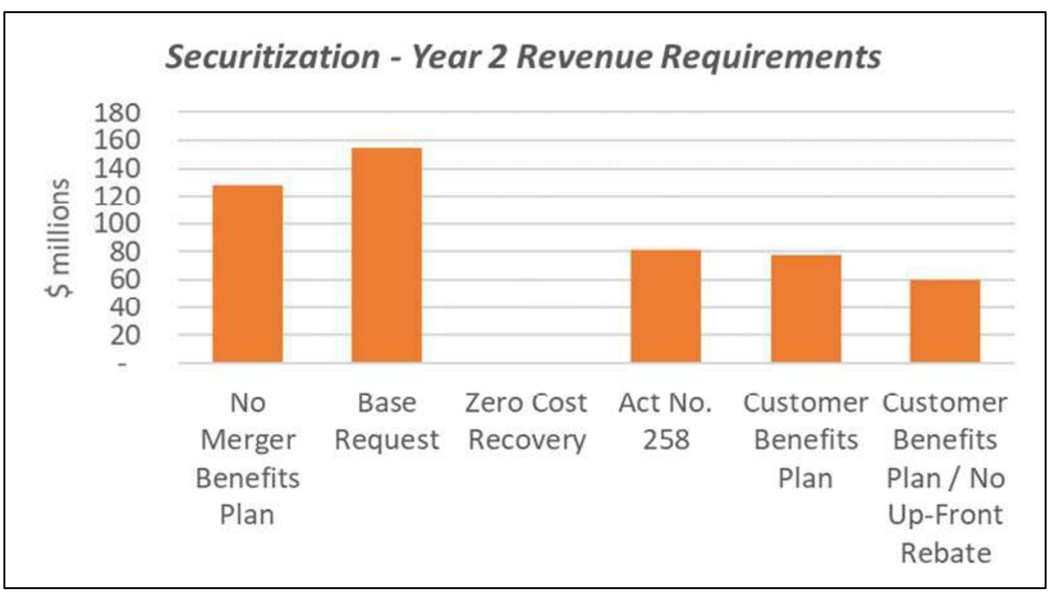

Figure 6: Securitization – Year 2 Revenue Requirements

Q Could a securitization scenario that does not involve a merger with Dominion provide similar savings to the Customer Benefits Plan?

A Yes. The No Merger Benefits Plan with securitization saves more than the Customer Benefits Plan with the Merger. The use of securitization with the No Merger Benefits Plan results in present value of revenue requirements ($1.5b) and ongoing annual costs ($128m in year 2) that are lower than the Customer Benefits Plan without securitization (PVRR of $1.6b and $313m in year 2).

Q Are there any other findings you would like to note?

A Yes. While the Customer Benefits Plan delivers the greatest savings to ratepayers when combined with securitization, altering some aspects of the Customer Benefits Plan would better balance of cost reductions and credit impacts. For example, while an up-front credit provides some immediate rate relief to customers, the use of securitization without the up-front credit could provide a better balance of cost reductions with impact on corporate credit rating.

I would also note that securitization offers further options that could mitigate any potential credit impact. For example, the securitized debt could be held by a special purpose vehicle created by the state rather than one owned by the utility, and the proceeds from the securitization could be used primarily to buy down older, more expensive debt, reducing interest expenses and overall leverage, thereby potentially improving the company's credit position. Exhibit UV-1 summarizes the quantitative results from my analysis.

V. SECURITIZATION CAN ALSO PROVIDE BENEFITS THROUGH THE USE OF "CAPITAL RECYCLING"

Q What other benefits can securitization provide?

A Securitization can provide substantial benefits for ratepayers and the Company that go beyond addressing the immediate challenge of financing nuclear cost recovery. Securitization provides the opportunity for the Company and its ratepayers to more easily take advantage of falling solar energy costs and the Federal Investment Tax Credit to replace generation from some of its more expensive generation assets with low cost solar generation. The capital infusion from refinancing with securitization can be recycled into clean energy investment, further reducing costs to customers and boosting utility profitability. This cheap, clean generation would lock in savings from Federal tax incentives and help transition SCE&G's existing fossil fleet to a cheaper, less polluting future. Further, if the legislation enabling securitization allows the Company to competitively procure solar generation assets and own them through an unregulated subsidiary, this replacement strategy could benefit the Company's shareholders and also save ratepayers money.[9]

Q How could securitization of the V.C Summer units be combined with securitization of other assets and what are the advantages of that strategy?

A Securitization has recently been used to reduce the cost to customers of retiring generation units before they are fully depreciated.[10] In SCE&G's case, there are several coal and natural gas fired units that solar is now cost competitive with, even on a

[9] See, for example, Utah's HB261, https://le.utah.gov/~2018/bills/static/HB0261.html.

[10] In 2014, Consumers Energy securitized nearly $400m in unrecovered plant balances associated with a portfolio of older coal assets, and in 2016 Duke Energy securitized $1.3b in costs associated with the decommissioning of a nuclear plant.

marginal cost basis. As Figure 7 shows below, the long-term marginal costs (operating expenses and fuel costs, based on data reported by the company in its FERC Form 1 submission for 2016) of the majority of SCE&G's older fossil generating assets (the dark blue bars) are greater than the regional cost of a solar PPA (dashed yellow line). This suggests that customers could save money if less fuel was burned at any of these facilities, and the generation was replaced with purchased power from a solar facility. However, customers would still be on the hook for paying the capital costs (the light blue bars) associated with these old facilities. Customers could save even more if the Company were to retire some of these plants and bundle the recovery of any outstanding plant balances with the securitization of the unrecovered V.C. Summer unit nuclear costs. That would increase the amount to be securitized, and provide capital that the Company could reinvest in cheap, clean energy, reducing rates for its customers while boosting its earnings.

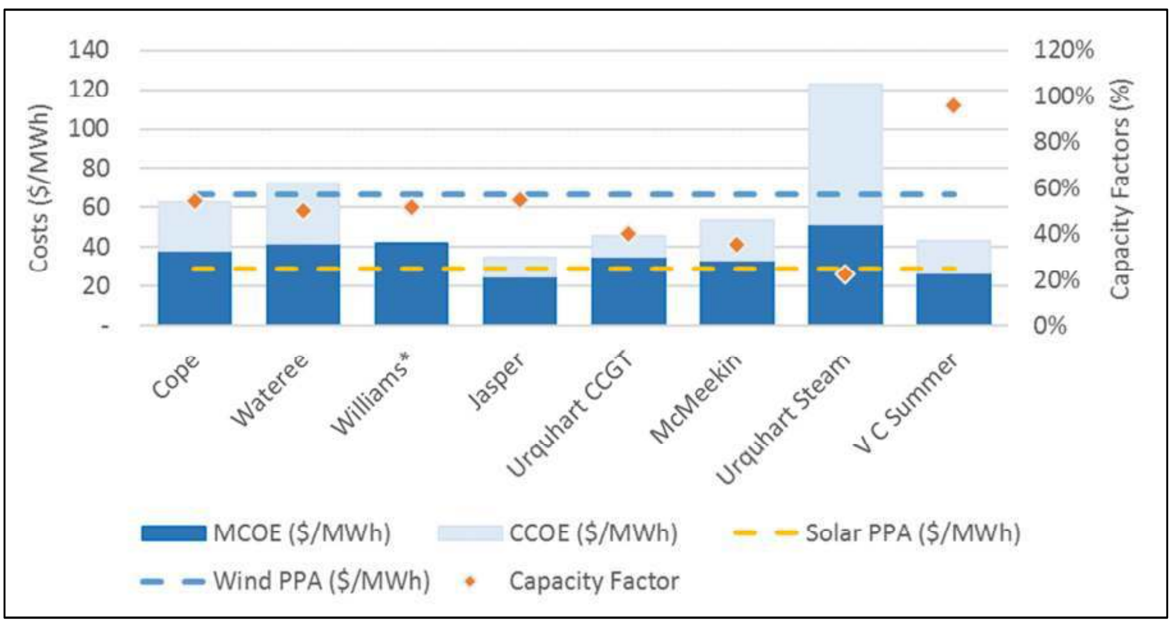

Figure 7: Comparison of the long-term marginal cost of electricity (sum of reported operating and fuel expenses – dark blue bars) and capital costs (light blue bars) of SCE&G's existing fossil plants with the total PPA price for new regional solar (dashed yellow line) and on-shore wind (dashed blue line). Note

that this simplified comparison of electricity costs on an annual / levelized basis does not capture differences in generation portfolio and grid services.

VI. CONCLUSION

Q Please summarize your recommendations.

A Given the substantial cost savings associated with securitization and potential to reinvest savings into clean energy generation, I agree with CCL and SACE witness Ron Binz that the Commission should consider requiring SCE&G and Dominion to use securitization for the recovery of any approved stranded costs of the abandoned V.C. Summer units, contingent of course on legislative action.

Q Does this conclude your testimony?

A Yes.

Impact of nuclear recovery costs on revenue requirements in the six scenarios analyzed

	PV of Revenue Requirements (in $ millions)	Year 1 Cost (in $ millions)	Year 2 Cost (in $ millions)
Act No. 258			
Regulatory Asset	1,381	154	134
Corporate Bond	1,009	116	99
Securitization	825	99	81
Customer Benefits Plan			
Regulatory Asset	1,614	(1,031)	313
Corporate Bond	668	(1,224)	133
Securitization	143	(1,281)	78
Customer Benefits Plan / No Up-Front Rebate			
Regulatory Asset	1,944	174	218
Corporate Bond	1,309	44	97
Securitization	957	6	60
No Merger Benefits Plan			
Regulatory Asset	2,997	300	277
Corporate Bond	2,023	194	178
Securitization	1,537	144	128
Base Request			
Regulatory Asset	3,942	385	361
Corporate Bond	2,617	240	224
Securitization	1,954	171	155
Zero Cost Recovery			
Regulatory Asset	0	0	0
Corporate Bond	0	0	0
Securitization	0	0	0